**Verso Androscoggin LLC**
**Franklin County**
**Jay, Maine**
**A-718-70-E-R/A**

**Departmental**
**Findings of Fact and Order**
**Part 70 Air Emission License**
**Renewal and Amendment**

## FINDINGS OF FACT

After review of the Part 70 License renewal and amendment application, staff investigation reports, and other documents in the applicant's file in the Bureau of Air Quality, pursuant to 38 M.R.S.A, §344 and §590, the Department finds the following facts:

## I. REGISTRATION

### A. Introduction

| | |
|---|---|
| FACILITY | Verso Androscoggin LLC |
| LICENSE TYPE | Part 70 License Renewal<br>Part 70 Significant License Modification<br>Part 70 Section 502(b)(10) Changes |
| NAICS CODES | 221112 |
| NATURE OF BUSINESS | Fossil Fuel Electric Power Generation |
| FACILITY LOCATION | Gate 15, Riley Road, Jay, Maine |

Verso Androscoggin LLC (Verso Cogen) is a fossil fuel firing electric power generation facility which provides steam to the Verso Androscoggin LLC pulp and paper mill in Jay, Maine, and electricity to the utility grid. The Cogen facility is located on the Riley Road through Gate 15 of the pulp and paper mill property in Jay, Maine. The facility consists of three identical cogeneration trains, which include combustion turbines (CTs) and heat recovery steam generators (HRSGs). Natural gas is the primary fuel for the combustion turbines, and low sulfur distillate fuel oil (which includes kerosene) with a maximum of 0.05% sulfur by weight is used as the secondary fuel. Emissions from the facility are formed from the combustion of natural gas and fuel oil in the three turbine generators and the combustion of natural gas only in the three heat recovery steam generator duct burners.

Verso Cogen has the potential to emit more than 100 tons per year (TPY) of particulate matter (PM), particulate matter under 10 micrometers in diameter ($PM_{10}$), particulate matter under 2.5 micrometers in diameter ($PM_{2.5}$), nitrogen oxides ($NO_x$), carbon monoxide (CO), and 100,000 tons of carbon dioxide equivalent ($CO_2e$); therefore, the source is a major source for criteria pollutants. Verso Cogen has the potential to emit more than 10 TPY of a single hazardous air pollutant (HAP) or more than 25 TPY of combined HAP; therefore, the source is a major source for HAP.

This facility was first licensed in 1998 with Air Emission License A-718-71-A-N, and the initial Part 70 license (A-718-70-A-I) was issued July 30, 2003. Verso Cogen has submitted an application for the renewal of their Part 70 Air Emission License. The renewal application included an amendment application to change the compliance demonstration method for ammonia ($NH_3$) emission limits from the use of $NH_3$ continuous emission monitors (CEMS) on the three cogeneration systems to the use of a compliance assurance monitor indicative of $NH_3$ slip. However, since the time that the significant modification and renewal application was submitted, the facility has developed an approved quality assurance program for the ammonia CEMS and no longer needs to pursue the significant modification described in the license application.

This license contains the renewal and amendments to incorporate Clean Air Act (CAA), Section 502(b)(10) operational changes requested since the renewal application was accepted as complete. These operational changes are as follows:

- Change the definition of "24-hour block average" as defined in Condition (14)(A) of Air Emission License A-718-70-A-I to read "not less than 18 one-hour block periods" instead of the current definition which reads "not less than 12 one-hour block periods." [letter of notification dated August 9, 2010]
- Change the definition for fuel transfer time allowed from one hour to 120 minutes. [letter of notification dated December 16, 2011]

## B. Emission Equipment

The following emission units are addressed by this Part 70 License:

**Fuel Burning Equipment**

| Equipment | Maximum *for Each Unit* Heat Input Capacity | Maximum *for Each Unit* Firing Rate, Fuel Type | Manuf. Date | Install. Date | Stack # |
|---|---|---|---|---|---|
| CT #1 | 675 MMBtu/hr each | 661,764 scf/hr natural gas (primary fuel)<br>4927 gal/hr low sulfur distillate oil (0.05% sulfur, secondary fuel) | 1999 | 1999 | 1 |
| CT #2 | | | | | 2 |
| CT #3 | | | | | 3 |
| HRSG #1 | 304 MMBtu/hr each | 298,039 scf/hr natural gas each | 1999 | 1999 | 1 |
| HRSG #2 | | | | | 2 |
| HRSG #3 | | | | | 3 |

| Equipment | Maximum *for Each Unit* Heat Input Capacity | Firing Rate, Fuel Type | Manuf. Date | Install. Date | Stack # |
|---|---|---|---|---|---|
| Glycol System Heater #1 | 3.05 MMBtu/hr each | 2990 scf/hr natural gas each | 1999 | 1999 | 4 |
| Glycol System Heater #2 | | | | | 5 |

**Process Equipment**

| Equipment | Capacity | Contents |
|---|---|---|
| Storage Tank #1 | 350,000 gallons | Low Sulfur Distillate Oil |

Verso Cogen has additional insignificant activities which do not need to be listed in the emission equipment tables above. The list of insignificant activities can be found in the Part 70 license application and in Appendix B of *Part 70 Air Emission License Regulations*, 06-096 CMR 140 (as amended).

**C. Application Classification**

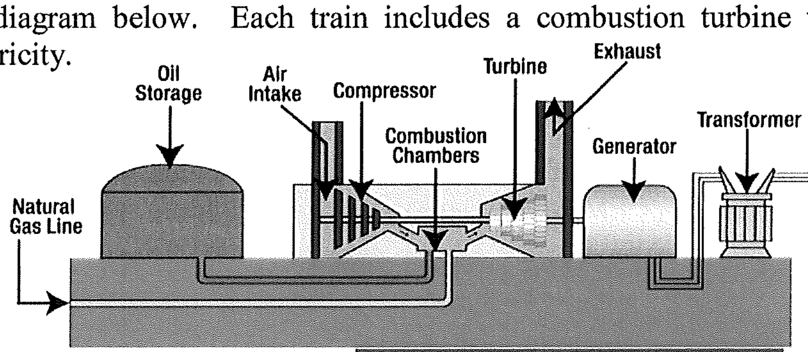
The application for Verso Cogen does not include the licensing of increased emissions or the installation of new or modified equipment. The requests for operational modifications do not include changes that would violate applicable requirements or contravene federally enforceable permit terms and conditions that are monitoring (including test methods), recordkeeping, reporting, or compliance certification requirements. These operational modifications are authorized and addressed per CAA Section 502(b)(10) and 06-096 CMR 140.

Therefore, this license is considered to be a Part 70 License renewal and CAA Section 502 (b)(10) Changes issued under *Part 70 Air Emission License Regulations*, 06-096 CMR 140 (as amended).

**D. Facility Description**

Verso Cogen operates a cogeneration system to supply energy in the form of steam to the Verso Androscoggin pulp and paper mill in Jay, Maine. The combustion turbines in the cogeneration system generate electricity for supply to the utility grid. This cogeneration facility is located within the Verso Androscoggin mill property boundary.

The cogeneration facility consists of three identical cogeneration trains, similar to the diagram below. Each train includes a combustion turbine that generates electricity.




http://www.tva.com/power/cumb_turbineart.htm

Combustion turbines are designed to start quickly to meet the demand for steam and/or electricity during peak demand periods. The turbines draw ambient air in at the front of the unit, compress it, mix it with fuel, and ignite it. The hot combustion gases then expand, causing turbine blades connected to a generator to turn to produce electricity.

At lower ambient temperatures, it takes less energy to compress the entering air; thus, more of the energy produced can be routed to the generator to produce electricity than during operation at higher ambient temperatures. Consequently, 50% of load level at lower ambient temperatures correlates to a greater quantity of MW generated than 50% of load level at higher ambient temperatures.

Combustion gases from each turbine exhaust to a heat recovery steam generator (HRSG), where steam is generated from residual energy in the turbine exhaust gases. Duct burners serve as a supplemental heat source for the HRSG and are fired during periods of increased steam demand. High and intermediate pressure steam is sent to the pulp and paper mill; low pressure steam is used for HRSG feed water de-aeration and other internal functions of the cogeneration system. Although Verso Cogen does not currently operate a steam turbine, excess steam developed in the HRSGs could be routed to a steam turbine to produces additional power, should the facility choose to install a steam turbine in the future.

Natural gas is the primary fuel for the combustion turbines and the only fuel for the duct burner systems. Low sulfur distillate fuel oil (0.05% sulfur) is used as the secondary fuel for the combustion turbines and is stored in a 350,000 gallon capacity above-ground storage tank. A Selective Catalytic Reduction (SCR) system, Dry Low-$NO_x$ combustors, and water injection are used to reduce $NO_x$ emissions from the combustion turbines and duct burners. An oxidation catalyst is located within each of the HRSGs downstream of the duct burners to reduce CO and VOC emissions from the cogeneration system.

**E. Significant Modification Description** – No Longer Applicable

Since the time the significant modification application was submitted to change the compliance demonstration method for $NH_3$, Verso Cogen has developed and implemented an approved quality assurance program for the ammonia continuous emissions monitoring system (CEMS) and has worked with its calibration gas suppliers to assure better conformity of the actual $NH_3$ concentration to the documented concentration as labeled on the bottle. Verso Cogen has and shall continue to follow the quality assurance program as described in this license and shall continue to use the ammonia monitor as an approved 06-096 CMR 117 CEMS. Thus, the significant modification application does not need to be acted upon. The following information presents clarification on the calibration gas audits for the $NH_3$ CEMS.

Verso Cogen implements a comprehensive quality assurance/quality control (QA/QC) program to ensure that all monitors function properly, provide reliable data, and conform to applicable regulatory standards. The facility has three turbine trains with three separate stacks, each monitored with $NO_x$ monitors and programmable logic controllers (PLCs) which calculate $NH_3$ concentration in the exhaust stream within a range of 0-to-20 ppm. The $NO_x$ analyzer sets on each turbine determine converted $NO_x$ from $NH_3$ and unconverted $NO_x$ (stack $NO_x$). The converted $NO_x$ is $NH_3$ converted to NO. The PLCs then calculate (converted $NO_x$) – (non-converted $NO_x$) = ($NH_3$). The calculation is based on the $NO_x$ differential from two samples before and after the $NH_3$-to-NO converter.

The facility conducts both daily $NO_x$ and daily $NH_3$ calibration checks, conducts quarterly calibration gas audits (CGAs) for the unconverted $NO_x$ data only (unconverted $NO_x$ analyzers only), and conducts annual relative accuracy test audits (RATAs) for both the $NO_x$ and the calculated $NH_3$ data. Verso Cogen does not, however, currently conduct CGAs for $NH_3$ specifically, for reasons including the following:

- CGAs are conducted for the unconverted $NO_x$ monitors used in the calculation of $NH_3$ concentrations on a quarterly basis. This performance check, coupled with the daily calibrations specific to $NH_3$ and the annual $NH_3$ RATA, assures that the analyzer is properly measuring the $NO_x$ samples used to calculate $NH_3$ emissions.
- The Federal Register does not include a published $NH_3$ CGA protocol; thus, Verso Cogen would have to default to the protocol identified in 40 CFR Part 60, Appendix F for $NO_x$. This standard, however, results in compromised accuracy and meaningfulness of the CGA testing process for an ammonia monitor in such a low concentration range, 0-to-20 ppm $NH_3$, as found at this facility.
- There are discrepancies between the designated ppm concentration of the $NH_3$ gas cylinders and the actual concentrations measured across all three of the CEM systems. When these discrepancies are found, the bottles are returned to the supplier, and the facility tests a new bottle before connecting it to all three analyzers for routine daily calibration checks.

Because of the lack of an applicable $NH_3$ CGA standard and the fact that application of the surrogate $NO_x$ CGA standard does not appear to yield a valuable performance test, the Department concurs with Verso Cogen's assertion that $NH_3$ CGAs are not appropriate for this facility at this time. This determination is further supported by the fact that the certified $NH_3$ bottle concentrations can vary up to a few ppm, further complicating the accuracy and meaningfulness of a potential $NH_3$ CGA testing process.

The Department finds that waiving the requirement for quarterly $NH_3$ CGAs on emissions from the three Combustion Turbines is justified and is granted in accordance with 06-096 CMR 117 (4)(B)(5)(b).

**F. Operational Modifications: 502(b)(10) Changes**

According to 06-096 CMR 140, changes within a Part 70 facility may be made without requiring a license revision if the changes are not modifications under 06-096 CMR 140 §5 and the changes do not cause emissions in excess of the standards in the license, whether expressed therein as a rate of emissions or in terms of total emissions. These changes are classified as Part 70 §502(b)(10) changes and may be made at any time during the term of the Part 70 license, provided that written notification is made to the EPA and the Department at least seven days in advance of the implementation of the proposed changes. The two operational modifications made at the Verso Cogen facility according to the 502(b)(10) process meet the required specifications.

502(b)(10) Change: *Definition of "24-hour Block Average"*
Prior to filing this 502(b)(10) change, the cogen facility was subject to multiple emission limitations that were based upon a 24-hour block average, comprised of not less than 12 and no more than 24 one-hour averages for each 24-hour block. These include emission limits for CO and $NO_x$ while natural gas is fired, while low sulfur distillate oil is fired, and during periods of startup, shutdown, and fuel transfer.

The facility supplies steam to the paper mill and electricity to the grid, operating based on steam and electricity demand and pricing. Since the facility is a demand driven facility, the CTs do not operate continuously, and it is not unusual for a CT to be brought online for less than 24 hours. This results in many startups for each CT, followed by limited hours of steady-state operation to satisfy steam or electricity demand. Emissions of $NO_x$ and CO are typically higher during the first hour or two of startup but drop quickly as the CT reaches steady state and stoichiometric combustion is achieved. Typical operating practice involves shutting down a CT in order to avoid any excess emission event associated with a monitored emission average. Prior to the 502(b)(10) change, a valid averaging period was based on 12 hours of operation. However, this operating scenario limited optimal functioning of the facility, especially during periods of high electricity demand, when the economics of generating electricity are most favorable.

This license includes changing the definition of a 24-hour block average to include "not less than 18 one-hour block periods," providing a longer averaging time in which to factor CO and $NO_x$ emissions that are higher during startup. Thus, the facility will not be penalized for operating the CTs for shorter periods of time in response to electrical demand.

In addition, since the submittal of the 502(b)(10) change, the definition of "valid data" in 06-096 CMR 117, *Source Surveillance - Emissions Monitoring*, has been revised to include "a twenty-four-hour average will be considered valid if it contains at least 18 valid hourly averages."

502(b)(10) Change: *Change of Fuel Transfer Time Definition*
As filed in a letter to the Department dated December 16, 2011, the facility proposed the change of the license condition specifying the definition of fuel transfer mode from "not to exceed 1 hour" to "not to exceed 120 minutes" to accommodate updated operational protocols. The change in defined transfer time allows for the facility to operate in accordance with the manufacturer's recommendations. Since the filing of this 502(b)(10) change, Verso Cogen has proposed that limitations on the time duration of startup, shutdown, and fuel transfer operating modes be removed from the license.

Although this facility has been previously licensed with time duration limits regarding startup, shutdown, and fuel transfer operating modes, the ramp rate for the turbine units is part of the integral design of the units, and the operating conditions of the turbines are programmed and specified by the manufacturer. Regardless of the turbine temperature, the typical startup curve involves adding between 1 to 1.2 MW per minute to the turbine; thus, startup is usually achieved within approximately one hour. The turbine cannot be ramped up faster than this due to equipment integrity (limits to heat increases across the HRSG).

Furthermore, the emission limits for $NO_x$ and CO during startup, shutdown, turbine re-tuning, and fuel transfer operating loads are based on 24-hour block averages, which will accommodate for fluctuations in emission rates (monitored via CEMS) during startup, shutdown, turbine re-tuning, and fuel transfer operating modes. If startup and control equipment are not achieved and engaged in an effective and timely manner, the 24-hour limits will not be met, and the unit will be shut down.

Therefore, Verso Cogen has proposed that limitations on the time duration of these events are not required for compliance purposes. The Department concurs with this proposal, and the time duration limits for startup, shutdown, and fuel transfer modes have been removed from the license. This renders as irrelevant this specific 502(b)(10) change.

## G. General Facility Requirements

Verso Cogen is subject to the following state and federal regulations listed below, in addition to the regulations listed for specific units as described further in this license.

| Citation | Requirement Title | Applicable Unit(s) |
|---|---|---|
| 06-096 CMR 101 | Visible Emissions | Facility |
| 06-096 CMR 102 | Open Burning | |
| 06-096 CMR 103 | Fuel Burning Equipment Particulate Emission Standard | |
| 06-096 CMR 106 | Low Sulfur Fuel | |
| 06-096 CMR 109 | Emergency Episode Regulation | |
| 06-096 CMR 110 | Ambient Air Quality Standard | |
| 06-096 CMR 116 | Prohibited Dispersion Techniques | |
| 06-096 CMR 117 | Source Surveillance | |
| 06-096 CMR 137 | Emission Statements | |
| 06-096 CMR 138 | $NO_x$ RACT | |
| 06-096 CMR 140 | Part 70 Air Emission License Regulations | |
| 06-096 CMR 143 | New Source Performance Standards | |
| 06-096 CMR 144 | National Emission Standards for Hazardous Air Pollutants (NESHAP) | |
| 06-096 CMR 148 | Emission from Smaller-Scale Electric Generating Sources | |
| 06-096 CMR 156 | $CO_2$ Budget Trading Program | |
| 40 CFR Part 60, Subpart Db | Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units | HRSG #1, #2, #3 |
| 40 CFR Part 60, Subpart GG | Standards of Performance for Stationary Gas Turbines | CT #1, #2, #3 |
| 40 CFR Part 63, Subpart DDDDD | National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters | Glycol System Heaters #1 and #2 |
| 40 CFR Part 68 | Chemical Accident Prevention Provisions | Facility |
| 40 CFR Part 70 | State Operating Permit Programs | |
| 40 CFR Part 72 | Permits Regulation (Acid Rain) | |
| 40 CFR Part 75 | Continuous Emissions Monitoring | |

Note: CMR = Code of Maine Regulations
CFR = Code of Federal Regulations

## H. Units of Measurement

The following units of measurement are used in this license:

| | |
|---|---|
| gr/dscf | grains per dry standard cubic feet |
| lb/hr | pounds per hour |
| lb/MMBtu | pounds per million British Thermal Units |
| lb/ton | pounds per ton |
| m/s | meters per second |

| | |
|---|---|
| mg/dscm | milligrams per dry standard cubic meters |
| MMBtu/hr | million British Thermal Units per hour |
| MMscf/year | million standard cubic feet per year |
| MW | megawatt |
| ng/dscm | nanograms per dry standard cubic meter |
| ppm | parts per million |
| ppmvd | parts per million by volume, dry basis |
| scf/hr | standard cubic feet per hour |
| tons/day | tons per day |
| tpy | tons per year |

## II. BEST PRACTICAL TREATMENT (BPT) AND EMISSION STANDARDS

### A. Introduction

In order to receive a license, the applicant must control emissions from each unit to a level considered by the Department to represent Best Practical Treatment (BPT), as defined in 06-096 CMR 100 (as amended). Separate control requirement categories exist for new and existing equipment as well as for those sources located in designated non-attainment areas.

BPT for existing emissions equipment means that method which controls or reduces emissions to the lowest possible level considering:

- the existing state of technology;
- the effectiveness of available alternatives for reducing emissions from the source being considered; and
- the economic feasibility for the type of establishment involved.

As summarized in the facility's initial license as Best Available Control Technology (BACT) and subsequent licenses as BPT, the air pollution control technologies identified in the table below are employed for the Cogeneration Systems.

| Unit | Pollutant | Control Strategy |
|---|---|---|
| Turbine | $NO_x$ | Water injection (during oil firing) |
| | | Low $NO_x$ combustors |
| HRSG | $NO_x$ | Low $NO_x$ burners |
| Turbine and HRSG | $NO_x$ | Selective Catalytic Reduction during gas firing only |
| | $SO_2$ | Combustion of low sulfur fuels |
| | CO | Catalytic Oxidation, good combustion practices |
| | PM, $PM_{10}$ | Good combustion practices, combustion of clean fuels |
| | VOC | Catalytic Oxidation, good combustion practices |

Each of the three cogeneration trains consists of a combustion turbine (CT) exhausting directly to a heat recovery steam generator (HRSG), which in turn exhausts to the stack. State and federal standards and requirements exist which apply to the turbines separately, to the steam generators separately, or to both together as a system. In the following sections of this Findings of Fact, specific requirements, as appropriate, are identified as applicable to specific parts of the cogeneration trains (Section II.G of this license for requirements specific to Combustion Turbines #1, #2, and #3; Section II.H for requirements specific to Heat Recovery Steam Generators #1, #2, and #3). For those pollutants for which standards and requirements apply for the entire cogeneration systems, discussion of these standards and requirements is contained in Section II.I of this license.

**B. Acid Rain**

Verso Cogen Combustion Turbines #1, #2, and #3 are subject to the federal Acid Rain Program, 40 CFR Part 70, *State Operating Permits Program*, and Part 72, *Permits Regulation*, and the facility is therefore required to have a Phase II acid rain permit. Verso Cogen was issued an acid rain permit, A-718-70-A-S, on November 12, 1998; the acid rain permit is incorporated into this renewal.

**C. $CO_2$ Budget Source**

Verso Cogen was issued license A-718-78-A-N, issued January 15, 2009, per Maine's *$CO_2$ Budget Trading Program*, 06-096 CMR 156 (as amended) for Combustion Turbines #1, #2, and #3. The $CO_2$ budget source license is incorporated into this renewal.

**D. NESHAPs 40 CFR Part 63, Subpart DDDDD: Boiler MACT**

Because Verso Cogen is a major source of HAP emissions, some emissions units at the facility are subject to the requirements of the federal regulation 40 CFR Part 63, Subpart DDDDD, *NESHAPs for Industrial, Commercial, and Institutional Boilers and Process Heaters*. This regulation establishes emissions limitations and work practice standards governing HAP emissions from units located at major sources of HAPs, for each unit which falls into one of the subcategories listed under *Types of Boilers and Process Heaters* in 40 CFR §63.7499. Specific requirements of Subpart DDDDD applicable to boilers and process heaters at this facility are addressed in each area specific to an affected unit.

**E. Compliance Assurance Monitoring (CAM)**

Federal regulation 40 CFR Part 64, *Compliance Assurance Monitoring,* is applicable to units at major sources if the unit has emission limits, a control device to meet the limits, and pre-control emissions greater than 100 tons/year for any pollutant. The turbines are equipped with advanced, Dry Low $NO_x$ burner technology to achieve low $NO_x$ emissions without the use of water injection when combusting natural gas. Water injection is used as $NO_x$ control during the combustion of low sulfur distillate oil, the water providing a heat sink that lowers the temperature, thereby reducing thermal $NO_x$ formation. Further emission reductions are obtained using a Selective Catalyst Reduction (SCR) and aqueous ammonia injection grid during the combustion of natural gas only. The turbines are equipped with an oxidation catalyst for CO emissions control.

Federal regulation 40 CFR Part 64 §64.2(b)(1)(vi) specifies the exemption from specific CAM requirements for any emission unit subject to emission limitations or standards for which a Part 70 air emission license specifies a continuous compliance determination method. The original BACT determination for the combustion turbines required included emission limitations monitored by the installation and operation of several CEMS, including $NO_x$ and CO, on the exhaust from each of the Cogeneration Systems #1, #2, and #3 as BACT. [A-718-71-A-N (March 31, 1998)]

Since Verso Cogen's Part 70 license specifies as part of the original BACT determination emission limitations which are continuously monitored by the CEMS for the combustion turbines to continuously demonstrate compliance with the $NO_x$ and CO emission limits, CAM requirements do not apply to these units. [40 CFR Part 64 §64.2(b)(1)(vi)]

## F. Reasonably Available Control Technology (06-096 CMR 138, $NO_x$-RACT)

*Reasonably Available Control Technology for Facilities that Emit Nitrogen Oxides ($NO_x$-RACT)*, 06-096 CMR 138, contains provisions for control of $NO_x$ emissions from stationary sources with the potential to emit quantities of $NO_x$ equal to or greater than 100 tons/year, such as the Verso Cogen facility. The cogen facility falls under part (3)(H) of this chapter as a miscellaneous stationary source. $NO_x$ RACT requirements are satisfied at the Verso Cogen facility through the operation of a $NO_x$ CEMS on each cogeneration system and the use of dry low $NO_x$ burner technology, water injection, and selective catalyst reduction and aqueous ammonia injection, reducing $NO_x$ emissions to below 4.5 ppm. [06-096 CMR 138]

## G. Facility Fuel Oil Use

Prior to January 1, 2016, the distillate fuel oil (kerosene) fired at the facility shall be ASTM D396 compliant low sulfur distillate oil (maximum sulfur content of 0.05% by weight). Per 38 MRSA §603-A(2)(A)(3), beginning January 1, 2016, the facility shall fire distillate fuel oil with a maximum sulfur content limit of 0.005% by weight (50 ppm) or as specified in the State Statute on this date; and beginning January 1, 2018, the facility shall fire distillate fuel oil with a maximum sulfur content limit of 0.0015% by weight (15 ppm) or as specified in the State Statute on this date.

Periodic monitoring for fuel oil use shall include recordkeeping to document fuel use both on a monthly and 12-month rolling total basis. Documentation shall include the type of fuel used and sulfur content of the fuel.

## H. Combustion Turbines #1, #2, and #3

Combustion Turbines (CT) #1, #2, and #3 are each Westinghouse Model number 251B12, dual fueled combustion turbines, each with eight burners firing pipeline natural gas as the primary fuel and low sulfur (0.05% by weight) distillate oil as secondary fuel. The maximum design heat input capacity of each CT is 675 MMBtu/hour. Each CT is coupled with a Brush electric generator that produces 50 MW, variable with ambient conditions. The CT units were manufactured and installed in 1999.

Emissions from the CT units exhaust through three closely grouped stacks. Each of these three stacks has an inside diameter of 153 inches and a height of 212 feet above ground level (AGL).

1. New Source Performance Standards (NSPS)

*NSPS 40 CFR Part 60, Subpart KKKK*
Because these three turbines were installed in 1999, they are not subject to New Source Performance Standards (NSPS) 40 CFR Part 60, Subpart KKKK – *Standards of Performance for Stationary Combustion Turbines*, which is applicable to stationary combustion turbines that commenced construction, modification, or reconstruction after February 18, 2005.

*NSPS 40 CFR Part 60, Subpart GG*
The three turbines are subject to New Source Performance Standards (NSPS) 40 CFR Part 60, Subpart GG – *Standards of Performance for Stationary Gas Turbines*, for which construction is commenced after October 3, 1977.

Pursuant to 40 CFR Part 60.333, $SO_2$ emissions are limited to either (a) 0.015% by volume @ 15% $O_2$ on a dry basis; or (b) the fuel sulfur content shall not exceed 0.8% by weight.

Pursuant to 40 CFR Part 60.332 (a)(1), $NO_x$ is limited based on the following equation: STD = (0.0075) x (14.4/Y) +F

where STD is the allowable $NO_x$ emissions (percent by volume at 15% $O_2$ and on a dry basis);

Y is a function of the manufacturer's rated load (kilojoules per watt hour); and

F is a function of the fuel-bound nitrogen.

Additionally, Verso Cogen is required to monitor the fuel-bound nitrogen and sulfur content of the fuel as required by Subpart GG. As of October 6, 2000, EPA approved an alternative monitoring schedule; therefore, Verso Cogen shall perform all monitoring in accordance with 40 CFR Part 60 Subpart GG and the February 1999 letter submitted to EPA.

Monitoring of the sulfur content of a gaseous fuel is not required when the gaseous fuel is determined to meet the definition of natural gas, including a limit of 20.0 grains of sulfur per 100 scf of "as delivered" fuel [40 CFR Part 60, Subpart GG §60.334(h)(3)]. Sulfur content monitoring of fuel oil shall be conducted in accordance with the alternative fuel monitoring schedule approved by the Department and EPA.

Monitoring of nitrogen content in natural gas and fuel oil is not required in accordance with the Department's letter of approval dated October 17, 2001. NSPS requires Verso Cogen to continuously monitor and record the fuel consumption and the ratio of water to fuel being fired. However, EPA's February 20, 2001, approval of Verso Cogen's alternative monitoring request authorizes the use of $NO_x$ CEMS to document compliance with Subpart GG instead of continuously monitoring the water-to-fuel ratio.

2. National Emissions Standards for Hazardous Air Pollutants (NESHAP)

Federal regulation 40 CFR Part 63, Subpart YYYY, *National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines*, establishes national emission limitations and operating limitations for hazardous air pollutants (HAP) emissions from stationary combustion turbines located at major sources of HAP emissions, and requirements to demonstrate initial and continuous compliance with the emission and operating limitations. These units are considered existing stationary combustion turbines because construction was commenced on or before January 14, 2003 [§ 63.6090 (a)(1)]. Therefore, according to 40 CFR 63.6090(b)(4), Combustion Turbines #1, #2, and #3 are not subject to the requirements of Subpart YYYY or Subpart A. The units would only become subject to Subpart YYYY in the event they are reconstructed as defined in 40 CFR 63.2.

3. Control Equipment

The turbines are equipped with advanced, Dry Low $NO_x$ burner technology to achieve low $NO_x$ emissions without the use of water injection when combusting natural gas. Water injection is used as $NO_x$ control during the combustion of low sulfur distillate oil, the water providing a heat sink that lowers the temperature, thereby reducing thermal $NO_x$ formation. Further emission reductions are obtained using a Selective Catalyst Reduction (SCR) and Aqueous Ammonia injection grid during the combustion of natural gas. The combination of Dry Low-$NO_x$ burners and SCR reduce $NO_x$ emissions to below 4.5 ppm.

The SCR system is utilized to reduce $NO_x$ emissions from the combustion turbines during natural gas firing but not during oil firing.

4. Emission Limits and Streamlining

Verso Cogen accepts streamlining for PM, $PM_{10}$, $SO_2$, and visible emissions requirements for these three units. Emission standards applicable to CT #1, #2, and #3 alone, the origin and authority of each standard, and the applicable emission limits and associated averaging periods after streamlining, as appropriate, are presented here. The origin and authority of the most stringent limit upon which the final, streamlined emission limit is based is presented in **bold type** in the following table.

**CT #1, #2, and #3 Streamlining Summary**

| Pollutant | Applicable Standards | Origin and Authority | Emission Limits |
|---|---|---|---|
| PM | 0.06 lb/MMBtu | **06-096 CMR 103** | 0.06 lb/MMBtu, 1-hour basis |
| | 6.27 lb/hr firing natural gas | **06-096 CMR 140, BPT** | 6.27 lb/hr, 1-hour basis firing natural gas |
| | 24.21 lb/hr firing distillate oil | | 24.21 lb/hr, 1-hour basis firing distillate oil |
| $PM_{10}$ | 6.27 lb/hr firing natural gas | **06-096 CMR 140, BPT** | 6.27 lb/hr, 1-hour basis firing natural gas |
| | 24.21 lb/hr firing distillate oil | | 24.21 lb/hr 1-hour basis firing distillate oil |
| $SO_2$ | 0.015% by volume @ 15% $O_2$ on a dry basis, **or** fuel sulfur content shall not exceed 0.8% by weight | 40 CFR §60.333 | 1.35 lb/hr, 1-hour basis firing natural gas |
| | 1.35 lb/hr firing natural gas | **06-096 CMR 140, BPT** | 32.38 lb/hr, 1-hour basis firing distillate oil |
| | 32.38 lb/hr firing distillate oil | | |
| Visible Emissions | 30% on a six-min. block average basis, except for no more than two six-min. block averages in a 3-hour period | 06-096 CMR 101, §2(B)(1)(f) | 20% opacity, on a six-min. block average basis, except for one six-minute block per hour of not more than 27% opacity |
| | 20% opacity, on a six-min. block average basis, except for one six-minute block per hour of not more than 27% opacity | **06-096 CMR 140, BPT** | |

5. Fuel Use Limit

As previously licensed, Verso Cogen distillate fuel oil use in the combustion turbines shall not exceed a combined total of 11,180,000 gallons of fuel oil with a maximum sulfur content not to exceed 0.05% by weight fired in the three turbines. This fuel cap is also less than 10% of the input capacity of the CTs; thus, for the purposes of the Acid Rain Program and of 40 CFR Part 75, these units are considered gas-fired combustion turbines.

A 2013 NSR license (A-718-77-1-A, issued May 13, 2013) authorized simultaneous firing of low sulfur distillate oil in all three turbines, with no change in the fuel use limit. The incorporation of the NSR license and corresponding Part 70 license condition amendment are incorporated into this license renewal.

6. Periodic and Parameter Monitoring

Verso Cogen shall operate monitors and record the following as specified for each of the Turbines #1, #2, and #3 whenever the equipment is operating.

| **Monitor *for Each* Combustion Turbine** | | | |
|---|---|---|---|
| **Parameter** | **Units** | **Monitoring Tool/Method** | **Frequency** |
| Fuel Oil Flow Rate | Gallons/hour | Fuel flow meter | Continuously* |
| Natural Gas Flow Rate | Scf/hour | Fuel flow meter | |
| Electric Output | MW | Electrical meter | |
| Low Sulfur Distillate Oil Sulfur Content | Percent, by weight | Fuel receipts from supplier | As fuel is purchased |
| Turbine Air Inlet Temperature | °F | Temperature probe | Continuously* |
| Turbine Electric Load Level | % | Electrical Output (MW) meter and Max. Potential Load (based on inlet air temperature and unit's discharge pressure) | |

*Continuously is defined as a minimum of three points in a one-hour period.

## I. Heat Recovery Steam Generators (HRSG) #1, #2, and #3

HRSGs #1, #2, and #3 are steam generators, each equipped with a duct burner rated at 304 MMBtu/hour heat input firing pipeline natural gas. The HRSGs are triple-pressure units providing high and intermediate pressure steam primarily to the steam headers at the Verso pulp and paper mill. Some of the steam is used for water/steam injection into the combustion turbines, and excess steam is used in the steam turbine for power generation. Low-pressure steam generated in the

HRSG is used primarily for HRSG feed water de-aeration and other internal functions of the cogeneration system.

1. New Source Performance Standards (NSPS)

*NSPS 40 CFR Part 60, Subpart D*
The units HRSG #1, #2, and #3 are not subject to NSPS requirements of 40 CFR Part 60, Subpart D – *Standards of Performance for Fossil Fuel Fired Steam Generators* because they meet the applicability requirements of paragraph (a) of §60.40b of 40 CFR Part 60, Subpart Db. [40 CFR Part 60, Subpart Db, §60.40b(j)]

*NSPS 40 CFR Part 60, Subpart Da*
These units are not subject to NSPS 40 CFR Part 60, Subpart Da, *Standards of Performance for Electric Utility Steam Generating Units*, for which construction is commenced after September 18, 1978, on the following basis: For each HRSG, no more than 33% of the potential electric output capacity and less than 25 MW electrical output will be supplied to any utility power distribution system for sale [40 CFR Part 60.40a(b)]. If Verso Cogen should install a steam turbine in the future or if changes in operating configuration cause these values to exceed the 33% and 25 MW thresholds, the facility may become subject to Subpart Da. Although they are not currently subject to Subpart Da, compliance with the conditions of this license also demonstrates compliance with the requirements of that Subpart.

*NSPS 40 CFR Part 60, Subpart Db*
The HRSGs are subject to 40 CFR Part 60, Subpart Db, *Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units*, which commence construction, modification, or reconstruction after June 19, 1984, and having heat input capacity of greater than 100 MMBtu/hour.

Contained in 40 CFR Part 60, Subpart Db, are emission limits, compliance and performance test specifications, emission monitoring requirements, and reporting and recordkeeping requirements for emissions of $SO_2$, PM, and $NO_x$ from affected facilities. Requirements pertaining to each pollutant are specified here.

| Pollutant | Applicable Emission Limit Determination | Basis for Determination |
|---|---|---|
| $SO_2$ | Because Verso Cogen combusts only natural gas in the HRSGs, the units are exempt from $SO_2$ emission limits of this Subpart. | 40 CFR Part 60, Subpart Db, §60.42b(k)(2) |
| PM | There is no PM emission limit specified in this Subpart for affected units firing only natural gas. | 40 CFR Part 60, Subpart Db, §60.43b |
| $NO_x$ | Limit of 0.20 lb/MMBtu | 40 CFR Part 60, Subpart Db, §60.44b(l)(1) |

The $NO_x$ emission standards apply at all times. [40 CFR Part 60, Subpart Db, §60.46b (a)] Compliance with the $NO_x$ emission standard shall be demonstrated by use of a CEMS specified under §60.48b for measuring $NO_x$ and $O_2$ and meeting the requirements of §60.48b. [40 CFR Part 60, Subpart Db, §60.46b (f)(2)]

Because Verso Cogen combusts only natural gas in the HRSGs, 40 CFR Part 60, Subpart Db does not impose emission limit requirements in addition to those described above.

2. National Emissions Standards for Hazardous Air Pollutants (NESHAP)

Federal regulation 40 CFR Part 63, Subpart DDDDD, *National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters* is applicable to industrial boilers or process heaters as defined in that Subpart and located at or are part of a major source of HAP. According to §63.7575 of Subpart DDDDD, waste heat boilers (which, according to the rule, are also referred to as heat recovery steam generators) are excluded from the definition of *boiler*.

Therefore, Subpart DDDDD is not applicable to HRSG #1, #2, or #3 at the Verso Cogen facility. [40 CFR Part 63, Subpart DDDDD]

3. Control Equipment

An SCR system is utilized to reduce $NO_x$ emissions from the duct burners when fuel oil is *not* being fired in the combustion turbines. The SCR system includes an injection grid which disperses $NH_3$ into the flue gas upstream of the catalyst; the $NH_3$ and $NO_x$ are reduced to nitrogen gas ($N_2$) and water vapor ($H_2O$) in the presence of the catalyst reactor. When fuel oil is being fired in the CT units, the SCR system is not engaged.

An oxidation catalyst is located within each of the HRSGs, downstream of the duct burner but before the SCR system, which reduces CO by 85% from both turbine and duct burner emissions. The oxidation catalyst also provides co-beneficial reduction of VOC in these emissions by an average of 15%.

4. Emission Limits and Streamlining

Verso Cogen accepts streamlining for PM, $PM_{10}$, $SO_2$, and visible emissions requirements for these three units. Emission standards applicable to HRSG #1, #2, and #3 alone, the origin and authority of each standard, and the applicable emission limits and associated averaging periods after streamlining, as appropriate, are presented here. The origin and authority of the most stringent limit upon which the final, streamlined emission limit is based is presented in **bold type** in the following table.

**HRSG #1, #2, and #3 Streamlining Summary**

| Pollutant | Applicable Standards | Origin and Authority | Emission Limits when firing… Natural Gas | Distillate Oil |
|---|---|---|---|---|
| PM | 0.06 lb/MMBtu | **06-096 CMR 103 and 40 CFR §60.42(e)** | 0.06 lb/MMBtu, 1-hour basis | |
| | 6.27 lb/hr firing natural gas<br>24.21 lb/hr firing distillate oil | **06-096 CMR 140, BPT** | 6.27 lb/hr, 1-hour basis | 24.21 lb/hr, 1-hour basis |
| $PM_{10}$ | 6.27 lb/hr firing natural gas<br>24.21 lb/hr firing distillate oil | **06-096 CMR 140, BPT** | 6.27 lb/hr, 1-hour basis | 24.21 lb/hr, 1-hour basis |
| $SO_2$ | 1.35 lb/hr firing natural gas<br>32.38 lb/hr firing distillate oil | **06-096 CMR 140, BPT** | 1.35 lb/hr, 1-hour basis | 32.38 lb/hr, 1-hour basis |
| Visible Emissions | 10% on a six-min. block average basis, except for no more than one six-min. block average in a 3-hour period *for HRSGs only (not applicable when CTs are firing fuel oil)* | 06-096 CMR 101, §2(B)(1)(c) | 20% opacity, on a six-minute block average basis, except for one six-minute block per hour of not more than 27% opacity | |
| | 20% opacity on a six-min. block average basis, except for no more than one six-min. block average in a 3-hour period | | | |
| | 20% opacity, on a six-min. block average basis, except for one six-minute block per hour of not more than 27% opacity | **40 CFR §60.42(a)(2)** | | |

5. Fuel Use Limit

As previously licensed, Verso Cogen natural gas use in the HRSG units shall not exceed a combined total of 2,637.2 million standard cubic feet per year (MMscf/year) of natural gas fired in the three HRSGs.

6. Periodic and Parameter Monitoring

Verso Cogen shall operate monitors and record the following parameters as specified for the HRSGs:

| Monitor for Each of HRSG #1, #2, and #3 | | | |
|---|---|---|---|
| **Parameter** | **Units** | **Monitoring Method** | **Frequency** |
| HRSG natural gas flow rate | scf/hour | Fuel flow meter | Continuously |

**J. Cogeneration System Requirements (CTs and HRSGs Together)**

1. Emission Limits: All Operation Except Startup, Shutdown, Turbine Re-Tuning, or Fuel Transfer

   For each cogeneration system, the results of streamlining of applicable emissions standards from above, the origin and authority of the standards, and the applicable emission limits and associated averaging periods are presented below. These limits apply during all operating times except startup, shutdown, turbine re-tuning, or fuel transfer.

| **Pollutant** | **Origin and Authority** | **Emission Standard** | |
|---|---|---|---|
| PM | 06-096 CMR 103 | 0.06 lb/MMBtu, 1-hour basis | |
| | *When the CT is Firing:* | *Natural Gas* | *Distillate Oil* |
| PM | 06-096 CMR 140, BPT | 6.27 lb/hr | 24.21 lb/hr, 1-hour basis |
| $PM_{10}$ | 06-096 CMR 140, BPT | 6.27 lb/hr | 24.21 lb/hr, 1-hour basis |
| $SO_2$ | 06-096 CMR 140, BPT | 1.35 lb/hr | 32.38 lb/hr, 1-hour basis |
| $NO_x$ | 06-096 CMR 140, BPT | 6.0 ppmvd @15% $O_2$, 24-hour block average basis | -- |
| | | 4.5 ppmvd @15% $O_2$, 30-day rolling average basis | -- |
| | | -- | 42 ppmvd @15% $O_2$, 3-hour block average basis |
| | *When the CT is Firing:* | *Natural Gas* | *Distillate Oil* |
| $NO_x$ | 06-096 CMR 140, BPT | 24.37 lb/hr, 24-hour block average basis | 133.25 lb/hr, 24-hour block average basis* |
| CO | 06-096 CMR 140, BPT | 74.21 lb/hr, 24-hour block average basis | 43.73 lb/hr, 24-hour block average basis* |
| VOC | 06-096 CMR 140, BPT | 2.13 lb/hr, 1-hour basis (only turbine firing only natural gas) | 8.0 lb/hr, 1-hour basis (only turbine firing only fuel oil or oil/natural gas combination) |
| | | 5.17 lb/hr, 1-hour basis (both turbine and HRSG firing natural gas) | 11.04 lb/hr, 1-hour basis (turbine firing fuel oil and HRSG firing natural gas) |
| Visible Emissions | 06-096 CMR 140, BPT | 20% opacity, on a six-min. block average basis, except for one six-minute block per hour of not more than 27% opacity | |
| $NH_3$ | 06-096 CMR 140, BPT | 10 ppmvd @ 15% $O_2$, 30-day rolling average basis | |
| | | 20 ppmvd @ 15% $O_2$, 24-hour block average basis | |

* $NO_x$ and CO lb/hour limit averaging times are based on a 24-hour block average basis to accommodate fluctuations in emission rates due to actual

operations, which include frequent start-ups and shut-downs in response to demand.

2. Emission Limits: Startup, Shutdown, Turbine Re-Tuning, or Fuel Transfer

Emissions from each of the Cogeneration Systems #1, #2, and #3 shall not exceed the following limits during periods of startup, shutdown, turbine re-tuning, or fuel transfer while firing natural gas or fuel oil.

| Pollutant | Emission Limit | |
|---|---|---|
| | lb/MMBtu | lb/hr |
| PM | 0.06 lb/MMBtu, 1-hour basis | -- |
| | -- | 24.21, 1-hour basis |
| $PM_{10}$ | -- | 24.21, 1-hour basis |
| $SO_2$ | -- | 32.38, 1-hour basis |
| $NO_x$ | -- | 133.25 24-hour block average basis* |
| CO | -- | 74.21 24-hour block average basis* |
| VOC | -- | 36.10, 1-hour basis |

* $NO_x$ and CO lb/hour limit averaging times are based on a 24-hour block average basis to accommodate fluctuations in emission rates due to actual operations, which include frequent start-ups and shut-downs in response to demand.

A *fuel transfer* mode shall be defined as the period of time during which the fuel fired in the turbine is switched from oil to gas or from gas to oil.

*Turbine startup* shall be defined as the continuous transition from initiation of combustion turbine fuel firing until the unit reaches steady state operation at a load between 50% and 100% load conditions firing natural gas, or at a load between 65% and 100% load conditions firing fuel oil. The normal rated load level compares the actual output of the turbine (MW) to the maximum potential output (MW) of the turbine at any given state of discharge pressure and inlet air temperature.

A unit is considered *down* once combustion turbine firing has ceased.

Unit *shutdown* shall be defined as that period of continuous transition from steady state operation within the load levels ranges identified in the *Turbine startup* definition above to cessation of combustion turbine firing.

*Turbine re-tuning* shall be defined as the time from initiation of combustion turbine firing until the turbine reaches base load.

3. Emission Limit Compliance Methods and Frequency

Compliance with the emission limits shall be demonstrated in accordance with the methods and frequencies indicated in the table below or other methods or frequencies as approved by the Department.

| Pollutant | Compliance Method | Frequency |
|---|---|---|
| PM | Stack Test according to Method as specified in 40 CFR Part 60, Appendix A | Upon Request |
| $PM_{10}$ | | |
| $SO_2$ | Stack Test according to Method as specified in 40 CFR Part 60, Appendix A | Upon Request |
| $NO_x$ | $NO_x$ CEMS | Continuously |
| CO | CO CEMS | |
| VOC | Stack Test according to Method as specified in 40 CFR Part 60, Appendix A | Upon Request |
| Visible Emissions | 40 CFR Part 60, Appendix A, Method 9 | |
| $NH_3$ | Stack Test according to Method as specified in 40 CFR Part 60, Appendix A | |

4. Continuous Emission Monitoring Systems (CEMS)

Periodic monitoring shall include continuous monitoring of $NO_x$, CO, $NH_3$, and $O_2$ emissions from each Cogeneration System. Verso Cogen accepts streamlining for applicable monitoring requirements from 40 CFR Parts 60 and 75 for the $NO_x$ and $O_2$ CEMS. The facility shall operate, calibrate, and maintain the $NO_x$ and $O_2$ CEMS and applicable monitoring devices according to 40 CFR Part 75. The CO and $NH_3$ (and $O_2$ diluent) CEMS are subject to the requirements of 06-096 CMR 117.

Note: The CO CEMS, $NH_3$ CEMS, and $O_2$ CEMS (to the extent that it acts as a diluent for the CO and $NH_3$ CEMS) are regulated by 40 CFR Part 60 and Maine DEP rule 06-096 CMR 117 which incorporates 40 CFR Part 60 by reference and includes state specific clarifications. The $NO_x$ CEMS and $O_2$ CEMS (to the extent that it acts as a diluent for $NO_x$) are regulated by 40 CFR Part 75 and Maine DEP rule 06-096 CMR 117; however, 40 CFR Part 75 supersedes Maine DEP rule 06-096 CMR 117.

Notwithstanding the above paragraphs, the $NH_3$ CEMS QA procedure shall include daily $NO_x$ and $NH_3$ calibration checks, quarterly calibration gas audits (CGAs) for the unconverted $NO_x$ data, and annual relative accuracy test audits (RATAs) for both the $NO_x$ and the calculated $NH_3$ data; CGAs specifically for $NH_3$ shall not be required.

The table below lists the required CEMS.

| Continuous Monitor | Unit of Measurement | Origin and Authority |
|---|---|---|
| $NO_x$ CEMS | lb/hr and ppmvd | 06-096 CMR 117 and 138 |
| CO CEMS | lb/hr | 06-096 CMR 117 |
| $O_2$ CEMS | ppm | |
| $NH_3$ CEMS | ppmvd | |

Verso Cogen is not required to continuously monitor opacity of emissions from the cogen systems, since the capacity factor for non-gaseous fuels is less than 30%, per 06-096 CMR 117 (1)(B)(1)(b). The fuel oil use cap for the combustion turbines limits the fuel oil combustion to less than 30% of capacity.

## K. Glycol System Heaters #1 and #2

Glycol System Heaters #1 and #2 each have a maximum capacity of 3.05 MMBtu/hour and fire natural gas.

1. NSPS 40 CFR Part 60, Subpart Dc

The heaters are not subject to NSPS 40 CFR Part 60, Subpart Dc – *Standards of Performance for Boilers Manufactured after June 9, 1989*, because they have maximum heat inputs of less than 10 MMBtu/hour.

2. BACT/BPT

The heaters underwent Best Available Control Technology (BACT) analysis during a previous licensing process. Those BACT determinations are now considered BPT for the units. BACT/BPT emission limits for the heaters are based on the following:

PM, $PM_{10}$ – 0.05 lb/MMBtu, 06-096 CMR 140, BACT/BPT
$SO_2$ – 0.6 lb/MMscf: AP-42, Table 1.4-2 (dated 7/98)
$NO_x$ – 100 lb/MMscf: AP-42, Table 1.4-1 (dated 7/98)
CO – 84 lb/MMscf: AP-42, Table 1.4-1 (dated 7/98)
VOC – 5.5 lb/MMscf: AP-42, Table 1.4-2 (dated 7/98)
Opacity – 06-096 CMR 101

The BACT/BPT emission limits for the two system heaters are the following:

| Unit | Emission Limit, lb/hr | | | | | |
|---|---|---|---|---|---|---|
| 3.05 MMBtu/hr each, natural gas | PM | $PM_{10}$ | $SO_2$ | $NO_x$ | CO | VOC |
| System Heater #1 | 0.15 | 0.15 | 0.01 | 0.3 | 0.25 | 0.02 |
| System Heater #2 | 0.15 | 0.15 | 0.01 | 0.3 | 0.25 | 0.02 |

Calculations are based on 3.05 MMBtu/hour and a fuel heat content of 1020 Btu/scf.

Compliance with emission limits for System Heaters #1 and #2 shall be demonstrated through stack testing in accordance with the appropriate method as specified in 40 CFR Part 60, Appendix A and upon request by the Department.

Visible emissions from either System Heater #1 or #2 firing natural gas shall not exceed 10% opacity on a six-minute block average basis, except for no more than one six-minute block average in a three-hour period.

3. NESHAPs 40 CFR Part 63, Subpart DDDDD

Under 40 CFR Part 63, Subpart DDDDD, System Heaters #1 and #2 are considered existing units designed to burn Gas 1, subject to work practice standards and related recordkeeping and reporting requirements for existing units designed to burn Gas 1, as defined in 40 CFR §63.7575. Verso Cogen must comply with this subpart no later than January 31, 2016. [40 CFR §63.7495(b)] However, some notifications must be submitted before the facility is required to comply with the applicable work practice standards and recordkeeping and reporting requirements. [40 CFR §63.7495(d)]

*Tune-Ups and Energy Assessments*
The facility shall complete initial tune-ups of the units by following the procedures described in § 63.7540(a)(10)(i) through (vi) no later than January 31, 2016. [40 CFR §63.7510(e)]

Subsequent tune-ups must be conducted every five years and as specified in §63.7540. [40 CFR §63.7500(e)]

Each five-year tune-up must be conducted no more than 61 months after the previous tune-up. [40 CFR §63.7515(d)]

The facility shall have a one-time energy assessment performed by a qualified energy assessor no later than January 31, 2016, or comply with any amended requirements of the rule. The energy assessment must include the elements specified in Part 4 of Table 3 of Subpart DDDDD, as applicable. [40 CFR §63.7500(e)]

Note: An energy assessment completed on or after January 1, 2008, that meets or is amended to meet the aforementioned energy assessment requirements is valid. A facility that operates under an energy management program compatible with ISO 50001 that includes applicable boilers and process heaters satisfies the energy assessment requirements.

*Recordkeeping*
Verso Cogen shall maintain records in accordance with 40 CFR §63.7555 and containing information necessary to document compliance with all applicable requirements, including but not limited to the following:

a. A copy of each notification and report submitted to comply with this Subpart, along with any supporting documentation.
b. Records of energy assessments and tune-ups, as applicable.

Verso Cogen shall maintain records in accordance with §63.10(b).

*Reporting*
Verso Cogen shall submit a compliance report for the one-time energy assessment, as applicable, and for each tune-up required by this Subpart in accordance with 40 CFR §63.7550.

**L. Fuel Storage Tank**

Verso Cogen maintains an oil storage tank which is currently used to store distillate oil. The tank is an above ground, steel, fixed-roof tank with a capacity of 350,000 gallons which was manufactured in 1998.

Oil Storage Tank #1 is not subject to NSPS 40 CFR Part 60, Subpart Kb – *Standards of Performance for Liquid Organic Storage Vessels (Including Petroleum Liquid Storage Vessels)*, constructed after July 23, 1984, because the vapor pressure of the tank contents is less than 3.5 kPa.

**M. Facility Annual Emissions**

1. Total Annual Emissions

Annual emissions for the purposes of the annual fee are calculated based on the following:

a. 11,180,000 gallons of fuel oil with a maximum sulfur content not to exceed 0.05% by weight fired in the three turbines, with natural gas fired at maximum capacity for the remainder of the year;
b. 2,637.2 MMscf of natural gas fired in the three HRSGs; and
c. Heaters #1 and #2 operating 8760 hours/year.

**Total Licensed Annual Emissions for the Facility**
**Tons/year**
(used to calculate the annual license fee)

| Unit | PM | $PM_{10}$ | $SO_2$ | $NO_x$ | CO | VOC | $NH_3$ |
|---|---|---|---|---|---|---|---|
| **Cogen Systems #1, #2, #3** | | | | | | | |
| With turbines firing oil | 28.1 | 28.1 | 39.4 | 154.5 | 362.3 | 49.8 | 62.7 |
| With turbines firing natural gas | 75.1 | 75.1 | 16.2 | 292.0 | 889.1 | | |
| **Heaters #1 and #2** | 0.7 | 0.7 | 0.01 | 1.3 | 1.1 | 0.1 | -- |
| **TOTALS** | **103.9** | **103.9** | **55.6** | **447.8** | **1252.5** | **49.9** | **62.7** |

The emissions listed above are based on specific worst case emission scenarios to determine the source's maximum potential to emit, as follows:

- The values for VOC and $NH_3$ emissions from Cogen Systems #1, #2, and #3 were calculated using worst case lb/hour emission rates. The VOC annual total includes an allowance to account for the higher licensed lb/hour VOC emission rate during startup, shutdown, and fuel transfer periods.
- Yearly emissions of $NH_3$ from the SCR System are calculated using average stack conditions to convert $NH_3$ limits in ppm to lb/hour limits. Based on historical stack test data, $NH_3$ emissions are higher when the turbines fire alone and lower when the turbines and the duct burners are operated simultaneously. Yearly $NH_3$ emissions were calculated based on maximum operation of the turbines without the duct burners operating.
- Yearly emissions of PM, $PM_{10}$, $SO_2$, $NO_x$, and CO were calculated based on firing the license allowed amount of fuel oil in the turbines while simultaneously firing the HRSGs, followed by firing the turbines at maximum capacity using natural gas while continuing to fire the HRSGs until the license allowed amount of natural gas for the steam generators is expended, after which the turbines are fired alone with natural gas at maximum capacity.
- The Heaters are assumed to fire natural gas at maximum capacity.

2. <u>Greenhouse Gases</u>

Greenhouse gases are considered regulated pollutants as of January 2, 2011, through 'Tailoring' revisions made to EPA's *Approval and Promulgation of Implementation Plans,* 40 CFR Part 52, Subpart A, §52.21 *Prevention of Significant Deterioration of Air Quality* rule. Greenhouse gases, as defined in 06-096 CMR 100 (as amended), are the aggregate group of the following gases: carbon dioxide, nitrous oxide, methane, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride. For licensing purposes, greenhouse gases (GHG) are calculated and reported as carbon dioxide equivalents ($CO_2e$).

Based on the facility's fuel use limits, the worst case emission factors from AP-42, IPCC (Intergovernmental Panel on Climate Change), and *Mandatory Greenhouse Gas Reporting*, 40 CFR Part 98, and the global warming potentials contained in 40 CFR Part 98, Verso Cogen is above the major source threshold of 100,000 tons of $CO_2e$ per year.

## III. AMBIENT AIR QUALITY ANALYSIS

Verso Cogen previously submitted an ambient air quality analysis demonstrating that emissions from the facility, in conjunction with all other sources, do not violate ambient air quality standards (see license A-718-71-A-N, issued March 31, 1998). An additional ambient air quality analysis is not required for this Part 70 License.

## ORDER

Based on the above Findings and subject to conditions listed below, the Department concludes that emissions from this source:

- will receive Best Practical Treatment;
- will not violate applicable emissions standards; and
- will not violate applicable ambient air quality standards in conjunction with emissions from other sources.

The Department hereby grants the Part 70 License A-718-70-E-R/A pursuant to 06-096 CMR 140 and the preconstruction permitting requirements of 06-096 CMR 115 and subject to the standard and specific conditions below.

All federally enforceable and State-only enforceable conditions in existing air licenses previously issued to Verso Cogen pursuant to the Department's preconstruction permitting requirements in 06-096 CMR 108 or 115 have been incorporated into this Part 70 license, except for such conditions that the Department has determined are obsolete, extraneous, or otherwise environmentally insignificant, as explained in the Findings of Fact accompanying this license. As such, the conditions in this license supercede all previously issued air emission license conditions.

Federally enforceable conditions in this Part 70 license may only be changed pursuant to the requirements of 06-096 CMR 115 for making such changes, as applicable, and pursuant to the applicable requirements of 06-096 CMR 140.

For each standard and specific condition which is state enforceable only, state-only enforceability is designated with the following statement: **Enforceable by State-only**.

Severability. The invalidity or unenforceability of any provision or part thereof of this License shall not affect the remainder of the provision or any other provisions. This License shall be construed and enforced in all respects as if such invalid or unenforceable provision or part thereof had been omitted.

## STANDARD STATEMENTS

(1) Approval to construct shall become invalid if the source has not commenced construction within eighteen (18) months after receipt of such approval or if construction is discontinued for a period of eighteen (18) months or more. The

Department may extend this time period upon a satisfactory showing that an extension is justified, but may condition such extension upon a review of either the control technology analysis or the ambient air quality standards analysis, or both; [06-096 CMR 140]

(2) The Part 70 license does not convey any property rights of any sort, or any exclusive privilege; [06-096 CMR 140]

(3) All terms and conditions are enforceable by EPA and citizens under the CAA unless specifically designated as state enforceable. [06-096 CMR 140]

(4) The licensee may not use as a defense in an enforcement action that the disruption, cessation, or reduction of licensed operations would have been necessary in order to maintain compliance with the conditions of the air emission license; [06-096 CMR 140]

(5) Notwithstanding any other provision in the State Implementation Plan approved by the EPA or Section 114(a) of the CAA, any credible evidence may be used for the purpose of establishing whether a person has violated or is in violation of any statute, regulation, or Part 70 license requirement. [06-096 CMR 140]

(6) Compliance with the conditions of this Part 70 license shall be deemed compliance with any Applicable requirement as of the date of license issuance and is deemed a permit shield, provided that:

A. Such Applicable and state requirements are included and are specifically identified in the Part 70 license, except where the Part 70 license term or condition is specifically identified as not having a permit shield; or

B. The Department, in acting on the Part 70 license application or revision, determines in writing that other requirements specifically identified are not applicable to the source, and the Part 70 license includes the determination or a concise summary, thereof.

Nothing in this section or any Part 70 license shall alter or affect the provisions of Section 303 of the CAA (*Emergency Powers*), including the authority of EPA under Section 303; the liability of an owner or operator of a source for any violation of Applicable requirements prior to or at the time of permit issuance; or the ability of EPA to obtain information from a source pursuant to Section 114 of the CAA.

The following requirements have been specifically identified as not applicable based upon information submitted by the licensee in an application dated January 30, 2008. [06-096 CMR 140]

| Source | Citation | Description | Basis for Determination |
|---|---|---|---|
| Facility | 06-096 CMR 134 | Reasonably Available Control Technology for Facilities that Emit Volatile Organic Compounds (VOC-RACT) | Fuel burning equipment is exempt from the requirements of this rule. |
| HRSGs | 40 CFR Part 60, Subpart D | Standards of Performance for Fossil Fuel Fired Steam Generators | The HRSGs meet the applicability requirements of paragraph (a) of §60.40b of 40 CFR Part 60, Subpart Db and are therefore not subject to Subpart D. [40 CFR Part 60, Subpart Db, §60.40b(j)] |
| HRSGs | 40 CFR Part 60, Subpart Da | Standards of Performance for Electric Utility Steam Generating Units for which Construction Commenced after September 18, 1978 | For each HRSG, no more than 33% of the potential electrical output capacity and less than 25 MW electrical output will be supplied to any utility power distribution system for sale [40 CFR Part 60.40a(b)]. |
| Glycol System Heaters #1 &#2 | 40 CFR Part 60, Subpart Dc | Standards of Performance for Boilers Manufactured After June 9, 1989 with Maximum Heat Inputs of More Than 10 MMBtu/hour | Units are smaller than threshold heat inputs. |
| Storage Tank #1 | 40 CFR Part 60, Subpart Kb | Standards of Performance for Volatile Organic Liquid Storage Vessels | The vapor pressure of the tank contents is less than 3.5 kPa. |
| Facility | 40 CFR Part 61, Subpart M | National Emission Standard for Asbestos | The cogen site does not contain asbestos. |
| CTs | 40 CFR Part 63, Subpart YYYY | NESHAP for Stationary Gas Turbines | The combustion turbines meet the definition of an existing source, which are not subject to the requirements of Subpart YYYY. |

(7) The Part 70 license shall be reopened for cause by the Department or EPA, prior to the expiration of the Part 70 license, if:

A. Additional Applicable requirements under the CAA become applicable to a Part 70 major source with a remaining Part 70 license term of 3 or more years. However, no opening is required if the effective date of the requirement is later than the date on which the Part 70 license is due to expire, unless the original Part 70 license or any of its terms and conditions has been extended pursuant to 06-096 CMR 140;

B. Additional requirements (including excess emissions requirements) become applicable to a Title IV source under the acid rain program. Upon approval by EPA, excess emissions offset plans shall be deemed to be incorporated into the Part 70 license;

C. The Department or EPA determines that the Part 70 license contains a material mistake or that inaccurate statements were made in establishing the emissions standards or other terms or conditions of the Part 70 license; or

D. The Department or EPA determines that the Part 70 license must be revised or revoked to assure compliance with the Applicable requirements.

The licensee shall furnish to the Department within a reasonable time any information that the Department may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating the Part 70 license or to determine compliance with the Part 70 license. [06-096 CMR 140]

(8) No license revision or amendment shall be required under any approved economic incentives, marketable licenses, emissions trading, and other similar programs or processes for changes that are provided for in the Part 70 license. [06-096 CMR 140]

## STANDARD CONDITIONS

(1) Employees and authorized representatives of the Department shall be allowed access to the licensee's premises during business hours or any time during which any emissions units are in operation, and at such other times as the Department deems necessary for the purpose of performing tests, collecting samples, conducting inspections, or examining and copying records relating to emissions and this license (38 M.R.S.A. §347-C).

(2) The licensee shall acquire a new or amended air emission license prior to commencing construction of a modification, unless specifically provided for in Chapter 140. [06-096 CMR 140]

(3) The licensee shall establish and maintain a continuing program of best management practices for suppression of fugitive particulate matter during any period of construction, reconstruction, or operation which may result in fugitive dust, and shall submit a description of the program to the Department upon request. [06-096 CMR 140] **Enforceable by State-only**

(4) The licensee shall pay the annual air emission license fee to the Department, calculated pursuant to 38 M.R.S.A. §353-A.

(5) The licensee shall maintain and operate all emission units and air pollution control systems required by the air emission license in a manner consistent with good air pollution control practice for minimizing emissions. [06-096 CMR 140] **Enforceable by State-only**

(6) The licensee shall retain records of all required monitoring data and support information for a period of at least six (6) years from the date of the monitoring

sample, measurement, report, or application. Support information includes all calibration and maintenance records, all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by the Part 70 license. The records shall be submitted to the Department upon written request or in accordance with other provisions of this license. [06-096 CMR 140]

(7) The licensee shall comply with all terms and conditions of the air emission license. The submission of notice of intent to reopen for cause by the Department, the filing of an appeal by the licensee, the notification of planned changes or anticipated noncompliance by the licensee, or the filing of an application by the licensee for the renewal of a Part 70 license or amendment shall not stay any condition of the Part 70 license. [06-096 CMR 140]

(8) In accordance with the Department's air emission compliance test protocol and 40 CFR Part 60 or other method approved or required by the Department, the licensee shall:

A. Perform stack testing under circumstances representative of the facility's normal process and operating conditions:

1. within sixty (60) calendar days of receipt of a notification to test from the Department or EPA, if visible emissions, equipment operating parameters, staff inspection, air monitoring or other cause indicate to the Department that equipment may be operating out of compliance with emission standards or license conditions;

2. to demonstrate compliance with the applicable emission standards; or

3. pursuant to any other requirement of this license to perform stack testing.

B. Install or make provisions to install test ports that meet the criteria of 40 CFR Part 60, Appendix A, test platforms if necessary, and other accommodations necessary to allow emission testing; and

C. Submit a written report to the Department within thirty (30) days from date of test completion.

[06-096 CMR 140] **Enforceable by State-only**

(9) If the results of a stack test performed under circumstances representative of the facility's normal process and operating conditions indicates emissions in excess of the applicable standards, then:

A. within thirty (30) days following receipt of such test results, the licensee shall re-test the non-complying emission source under circumstances representative of the facility's normal process and operating conditions and in accordance with the Department's air emission compliance test protocol and 40 CFR Part 60 or other method approved or required by the Department; and

B. the days of violation shall be presumed to include the date of stack test and each and every day of operation thereafter until compliance is demonstrated under normal and representative process and operating conditions, except to the extent that the facility can prove to the satisfaction of the Department that there were intervening days during which no violation occurred or that the violation was not continuing in nature; and

C. the licensee may, upon the approval of the Department following the successful demonstration of compliance at alternative load conditions, operate under such alternative load conditions on an interim basis prior to a demonstration of compliance under normal and representative process and operating conditions.

[06-096 CMR 140] **Enforceable by State-only**

(10) The licensee shall maintain records of all deviations from license requirements. Such deviations shall include but are not limited to malfunctions, failures, downtime, and any other similar change in operation of air pollution control systems or the emission unit itself that is not consistent with the terms and conditions of the air emission license.

A. The licensee shall notify the Commissioner within 48 hours of a violation of any emission standard and/or a malfunction or breakdown in any component part that causes a violation of any emission standard, and shall report the probable cause, corrective action, and any excess emissions in the units of the applicable emission limitation;

B. The licensee shall submit a report to the Department on a quarterly basis if a malfunction or breakdown in any component part causes a violation of any emission standard, together with any exemption requests.

Pursuant to 38 M.R.S.A. § 349(9), the Commissioner may exempt from civil penalty an air emission in excess of license limitations if the emission occurs during start-up or shutdown or results exclusively from an unavoidable malfunction entirely beyond the control of the licensee and the licensee has taken all reasonable steps to minimize or prevent any emission and takes corrective action as soon as possible. There may be no exemption if the malfunction is caused, entirely or in part, by poor maintenance, careless operation, poor design, or any other reasonably preventable condition or preventable equipment breakdown. The burden of proof is on the licensee seeking the exemption under this subsection.

C. All other deviations shall be reported to the Department in the facility's semiannual report.

[06-096 CMR 140]

(11) Upon the written request of the Department, the licensee shall establish and maintain such records, make such reports, install, use, and maintain such monitoring equipment, sample such emissions (in accordance with such methods, at such locations, at such intervals, and in such manner as the Department shall prescribe), and provide other information as the Department may reasonably require to determine the licensee's compliance status. [06-096 CMR 140]

(12) The licensee shall submit semiannual reports of any required periodic monitoring. All instances of deviations from Part 70 license requirements must be clearly identified in such reports. All required reports must be certified by a responsible official. [06-096 CMR 140]

(13) The licensee shall submit a compliance certification to the Department and EPA at least annually, or more frequently if specified in the applicable requirement or by the Department. The compliance certification shall include the following:

A. The identification of each term or condition of the Part 70 license that is the basis of the certification;
B. The compliance status;
C. Whether compliance was continuous or intermittent;
D. The method(s) used for determining the compliance status of the source, currently and over the reporting period; and
E. Such other facts as the Department may require to determine the compliance status of the source.

[06-096 CMR 140]

## SPECIFIC CONDITIONS

(14) **Definitions of Averaging Times** [06-096 CMR 140, BPT]

The following shall apply to the conditions in this order as appropriate, unless it is stated otherwise for such unit:

A. A 24-hour block average basis shall be calculated as the arithmetic average of not more than 24 one-hour block periods, and not less than 18 one-hour block periods. Only one 24-hour block average shall be calculated for one day, beginning at midnight.

B. A 3-hour block average basis shall be calculated as the arithmetic average of not more than three one-hour block periods. No more than eight three-hour block averages shall be calculated for one day. One three-hour block average shall be calculated for the period from midnight to 3:00 a.m., one from 3:00 a.m. to 6:00 a.m., one from 6:00 a.m. to 9:00 a.m., etc.

C. A 30-day rolling average basis shall be performed as described in 40 CFR Part 60, Subpart Db.

(15) **Cogeneration Systems #1, #2, and #3**

A Cogeneration System shall consist of a combustion turbine followed by a duct burner fired heat recovery steam generator (HRSG).

The exhaust from each Cogeneration System shall be vented through a separate flue to one of the three closely bundled, separate stacks at least 212 feet above ground level. [06-096 CMR 140, BPT]

A. Combustion Turbines #1, #2, and #3

*Fuel Oil Constraints*

1. Prior to January 1, 2016, the low sulfur distillate oil fired at the facility shall be ASTM D396 compliant (maximum sulfur content of 0.05% by weight). [06-096 CMR 115, BPT]

2. Beginning January 1, 2016, distillate oil fired at the facility shall have a maximum sulfur content limit of 0.005% by weight (50 ppm) or as specified in the statue 38 MRSA §603-A(2)(A)(3). [38 MRSA §603-A(2)(A)(3)]

3. Beginning January 1, 2018, distillate oil fired at the facility shall have a maximum sulfur content limit of 0.0015% by weight (15 ppm) or as specified in the statue 38 MRSA §603-A(2)(A)(3). [38 MRSA §603-A(2)(A)(3)]

4. To comply with this condition, distillate fuel oil purchased for use in the combustion turbines shall have a sulfur content not to exceed by weight as outline above, as applicable on the date of purchase.

5. Compliance shall be demonstrated by fuel records from the supplier showing the quantity, type, and percent sulfur of the fuel delivered. Records of annual fuel use shall be kept on both a monthly and a 12-month rolling total basis. [06-096 CMR 140, BPT]

6. Verso Cogen shall not exceed a facility fuel oil use of 11,180,000 gallons per year. Compliance with the facility fuel limit shall be demonstrated

using fuel flow monitors on a monthly and a 12-month rolling total basis. [A-718-70-A-I (July 30, 2003)]

*$NO_x$ and CO Emission Limits: Compliance Documentation*

7. For each hour that any fuel oil is fired in Turbine #1, Turbine #2, or Turbine #3, the monitored $NO_x$ ppmvd emissions shall not be included in determining compliance with the natural gas $NO_x$ ppmvd 30-day rolling and 24-hour block average emission limits as specified in this Order for such turbines that are firing fuel oil.

8. For each hour that any fuel oil is fired in Turbine #1, Turbine #2, or Turbine #3, the monitored $NO_x$ ppmvd emissions shall be used to comply with the emission limits as specified in this license for fuel oil firing for such turbines that are firing fuel oil.

9. Any portion of a block hour in which fuel oil is fired in a turbine shall be considered a monitored block hour ppmvd emission and included in the average to demonstrate compliance with the fuel oil firing ppmvd limits.

10. Hours affected by startup and shutdown shall not be included in the 24-hour and 3-hour $NO_x$ emissions block averages above.

11. For any portion of a calendar day in which fuel oil is fired in a turbine, the monitored $NO_x$ and CO lb/hour emissions for that calendar day shall be included in the average to demonstrate compliance with the fuel oil firing lb/hour limits, as appropriate, for that turbine firing fuel oil.

[A-718-70-A-I (July 30, 2003), BPT]

B. HRSG #1, #2, and #3

1. Only natural gas shall be fired in the duct burners of HRSG #1, #2, and #3.

2. Verso Cogen shall not exceed the combined natural gas fuel use limit of 2,637.2 MMscf/year fired in HRSGs #1, #2, and #3.

3. Compliance shall be demonstrated using fuel flow monitors on a monthly and a 12-month rolling total basis. [A-718-70-A-I (July 30, 2003), BPT]

C. Control Equipment

Verso Cogen shall engage the air pollution control strategies identified in the table below whenever the emission unit or units are in operation, except that the SCR system need not operate during a turbine startup, shutdown, turbine re-tuning, or fuel transfer period. [A-718-70-A-I (July 30, 2003), BPT]

| Unit | Pollutant | Control Strategy |
|---|---|---|
| Turbine | $NO_x$ | Water injection (during oil firing only) |
| | | Low $NO_x$ combustors |
| HRSG | $NO_x$ | Low $NO_x$ burners |
| Turbine and HRSG | $NO_x$ | Selective Catalytic Reduction during gas firing only |
| | $SO_2$ | Combustion of low sulfur fuels |
| | CO | Catalytic Oxidation, good combustion practices |
| | PM, $PM_{10}$ | Good combustion practices, combustion of clean fuels |
| | VOC | Catalytic Oxidation, good combustion practices |

D. Cogeneration Systems #1, #2, and #3 Emission Limits

Emissions from the Cogeneration Systems #1, #2, and #3 shall not exceed the following, except during startup, shutdown, turbine re-tuning, or fuel transfer, at which times they shall not exceed the limits given in Condition (15)(E) of this license:

| Pollutant | Origin and Authority | Emission Standard | |
|---|---|---|---|
| PM | 06-096 CMR 103 | 0.06 lb/MMBtu, 1-hour basis | |
| | *When the CT is Firing:* | *Natural Gas* | *Distillate Oil* |
| PM | 06-096 CMR 140, BPT | 6.27 lb/hr | 24.21 lb/hr, 1-hour basis* |
| $PM_{10}$ | 06-096 CMR 140, BPT | 6.27 lb/hr | 24.21 lb/hr, 1-hour basis* |
| $SO_2$ | 06-096 CMR 140, BPT | 1.35 lb/hr | 32.38 lb/hr, 1-hour basis* |
| $NO_x$ | 06-096 CMR 140, BPT | 6.0 ppmvd @15% $O_2$, 24-hour block average basis | -- |
| | | 4.5 ppmvd @15% $O_2$, 30-day rolling average basis | -- |
| | | -- | 42 ppmvd @15% $O_2$, 3-hour block average basis |
| | 06-096 CMR 140, BPT | 24.37 lb/hr, 24-hour block average basis | 133.25 lb/hr, 24-hour block average basis** |
| CO | 06-096 CMR 140, BPT | 74.21 lb/hr, 24-hour block average basis | 43.73 lb/hr, 24-hour block average basis** |
| | *When the CT is Firing:* | *Natural Gas* | *Distillate Oil* |
| VOC | 06-096 CMR 140, BPT | 2.13 lb/hr, 1-hour basis* (only turbine firing only natural gas) | 8.0 lb/hr, 1-hour basis * (only turbine firing only fuel oil or oil/natural gas combination) |
| | | 5.17 lb/hr, 1-hour basis* (both turbine and HRSG firing natural gas) | 11.04 lb/hr, 1-hour basis* (turbine firing fuel oil and HRSG firing natural gas) |

| Pollutant | Origin and Authority | Emission Standard |
|---|---|---|
| Visible Emissions | 06-096 CMR 140, BPT | 20% opacity, on a six-min. block average basis, except for one six-minute block per hour of not more than 27% opacity |
| $NH_3$ | 06-096 CMR 140, BPT | 10 ppmvd @ 15% $O_2$, 30-day rolling average basis |
| | | 20 ppmvd @ 15% $O_2$, 24-hour block average basis |

* 1-hour basis means compliance is demonstrated by the average of three one-hour compliance runs upon request of the Department to conduct stack testing.

** $NO_x$ and CO lb/hour limit averaging times are based on a 24-hour block average basis to accommodate fluctuations in emission rates due to actual operations, which include frequent start-ups and shut-downs in response to demand.

E. Emission Limits: Startup, Shutdown, Turbine Re-Tuning, and Fuel Transfer

1. Emissions from each of the Cogeneration Systems #1, #2, and #3 shall not exceed the following limits during periods of startup, shutdown, turbine re-tuning, or fuel transfer while firing either natural gas or fuel oil. [06-096 CMR 140, BPT]

| | Emission Limit | |
|---|---|---|
| Pollutant | lb/MMBtu | lb/hr |
| PM | 0.06, 1-hour basis | -- |
| | -- | 24.21, 1-hour basis |
| $PM_{10}$ | -- | 24.21, 1-hour basis |
| $SO_2$ | -- | 32.38, 1-hour basis |
| $NO_x$ | -- | 133.25, 24-hour block average basis* |
| CO | -- | 74.21, 24-hour block average basis* |
| VOC | -- | 36.10, 1-hour basis |

* $NO_x$ and CO lb/hour limit averaging times are based on a 24-hour block average basis to accommodate fluctuations in emission rates due to actual operations, which include frequent start-ups and shut-downs in response to demand.

2. A fuel transfer mode shall be defined as the period of time during which the fuel fired in the turbine is switched from oil to gas or from gas to oil. [06-096 CMR 140, BPT]

3. A turbine startup shall be defined as the continuous transition from initiation of combustion turbine fuel firing until the unit reaches steady state operation at a load between 50% and 100% load conditions firing

natural gas, or at a load between 65% and 100% load conditions firing fuel oil.

4. A unit is considered down once combustion turbine firing has ceased.

5. Unit shutdown shall be defined as that period of continuous transition from steady state operation within the load levels ranges identified in the *Turbine startup* definition above to cessation of combustion turbine firing. [06-096 CMR 140, BPT]

6. Turbine re-tuning shall be defined as the time from initiation of combustion turbine firing until the turbine reaches base load.

F. Periodic and Parameter Monitoring

Verso Cogen shall operate monitors and record the following as specified for each of the Turbines #1, #2, and #3 whenever the equipment is operating.

| **Monitor *for Each* Combustion Turbine** | | | |
|---|---|---|---|
| **Parameter** | **Units** | **Monitoring Tool/Method** | **Frequency** |
| Turbine fuel oil flow rate | Gallons/hour | Fuel flow meter | Continuously |
| Turbine natural gas flow rate | Scf/hour | Fuel flow meter | Continuously |
| #2 fuel oil sulfur content | Percent, by weight | Fuel receipts from supplier | As fuel is purchased |
| Electrical output | MW | Electrical meter | Continuously |
| Turbine Air Inlet Temperature | °F | Temperature probe | Continuously |
| Turbine Electric Load Level | % | Electrical Output (MW) meter and Max. Potential Load (based on inlet air temperature and unit's discharge pressure) | |
| **Monitor *for Each* HRSG** | | | |
| **Parameter** | **Units** | **Monitoring Tool/Method** | **Frequency** |
| HRSG natural gas flow rate | scf/hour | Fuel flow meter | Continuously |

For the purpose of this requirement, *Continuously* is defined as a minimum of three points in a one-hour period and two points in a one-hour period when maintenance or calibrations occur. [06-096 CMR 140, BPT]

G. Emission Limit Compliance Methods

Compliance with the emission limits shall be demonstrated in accordance with the methods and frequencies indicated in the table below or other methods or frequencies as approved by the Department. [06-096 CMR 140, BPT]

| Pollutant | Compliance Method | Frequency |
|---|---|---|
| PM | Stack testing using the appropriate method in 40 CFR Part 60, Appendix A | Upon Request |
| $PM_{10}$ | | |
| $SO_2$ | | |
| $NO_X$ | $NO_x$ CEMS | Continuously |
| CO | CO CEMS | |
| VOC | Stack testing using the appropriate method in 40 CFR Part 60, Appendix A | Upon Request |
| Visible Emissions | 40 CFR Part 60, Appendix A, Method 9 | |
| $NH_3$ | Stack testing using the appropriate method in 40 CFR Part 60, Appendix A | |

H. Continuous Emission Monitoring Systems (CEMS)

1. Verso Cogen shall operate and maintain the following CEMS for each Cogeneration System:

| Continuous Monitor | Unit of Measurement | Origin and Authority |
|---|---|---|
| $NO_x$ CEMS | lb/hr and ppmvd | 06-096 CMR 117 and 138 |
| CO CEMS | lb/hr | 06-096 CMR 117 |
| $O_2$ CEMS | ppm | |
| $NH_3$ CEMS | ppmvd | |

2. The facility shall operate, calibrate, and maintain all CEMS and applicable monitoring devices according to the following:

| In accordance with... | For these CEMS... |
|---|---|
| 40 CFR Part 75 | $NO_x$ and $O_2$ |
| 06-096 CMR 117 | CO and $NH_3$ (and $O_2$ diluent), with certain exceptions applicable to the $NH_3$ CEMS, calibration procedures for which are specified in the following paragraphs. |

3. Notwithstanding the above, the $NH_3$ CEMS QA procedure shall include daily $NO_x$ and $NH_3$ calibration checks, quarterly CGAs for the unconverted $NO_x$ data only (unconverted $NO_x$ analyzers only), and annual

RATAs for both the $NO_x$ and the calculated $NH_3$ data; CGAs specifically for $NH_3$ shall not be required in this license.

4. Verso Cogen shall continuously monitor and record NOx emission from each cogeneration train using NOx CEMS. EPA has determined this method of NOx monitoring to be an appropriate alternative means for demonstrating compliance with 40 CFR Part 60.334(a). Records shall be maintained according to Standard Condition (6) of this license and 40 CFR Part 60, Subpart GG.

[06-096 CMR 115 and 117; 40 CFR Part 60, Subpart GG; 40 CFR Part 75]

I. VOC Emissions Calculation Method [06-096 CMR 140, BPT]

1. Verso Cogen shall not exceed 49.9 tons/year of VOC emissions on a facility wide basis. Verso Cogen shall track fuel use in each CT, HRSG, and in Heaters #1 and #2 during normal operation on a 12-month rolling total basis. Verso Cogen shall also track the time spent in startup, shutdown, and fuel transfer modes. [06-096 CMR 140, BPT]

2. VOC emissions under normal operating conditions shall be calculated using the following methods:

   a. Turbines firing low sulfur distillate fuel oil:

   A = (a) (0.00041 lb VOC/MMBtu) (1 ton/2000 lb)

   where A = ton VOC/year
   a = 12-month rolling total of heat input from fuel oil, in MMBtu/year

   b. Turbines firing natural gas:

   B = (b) (0.0021 lb VOC/MMBtu) (1 ton /2000 lb)

   where B = ton VOC/year
   b = 12-month rolling total of heat input from natural gas, in MMBtu/year

   c. HRSG and Heaters #1 and #2 firing natural gas:

   C = (c) (0.0054 lb VOC/MMBtu) (1 ton/2000 lb)

   where C = ton VOC/year
   c = 12-month rolling total of heat input from natural gas, in MMBtu/year

d. Under startup, shutdown, or fuel transfer periods, VOC emissions shall be calculated from the lb/hour emission limit as required in Specific Condition (15)(E) as follows:

D = (d)(36.10 lb VOC/hour) (1 ton/2000 lb)

where D = ton VOC/year
d = hours of startup, shutdown, or fuel transfer periods in the most recent 12 months

e. Total facility VOC emissions (tons/year) = A+B+C+D

f. Total facility VOC emissions (tons/year) $\leq$ 49.9 tons/year.

(16) **Cogen System NSPS Monitoring** [40 CFR Part 60, Subpart GG]

Verso Cogen shall monitor the fuel-bound nitrogen and sulfur contents of the natural gas and fuel oil as described in 40 CFR Part 60, Subpart GG or as approved by the Department. This facility has received approval from the Department for the following alternative fuel monitoring schedule.

A. *Natural Gas*

1. Nitrogen Content Monitoring: No monitoring of fuel nitrogen content is required.

2. Sulfur Content Monitoring: Not required when fuel is demonstrated by the methods of §60.334(h)(3) to meet the definition of "natural gas" from §60.331(v) of Subpart GG.

B. *Distillate Oil*

Verso Cogen will replace the oil in the storage tank on a batch basis, which results in multiple delivery trucks for each filling event. A filling event will be considered all deliveries received in a calendar day.

1. Nitrogen Content Monitoring: No monitoring of fuel nitrogen content is required.

2. Sulfur Monitoring: A receipt identifying sulfur content shall be obtained from each fuel supplier for each filling event.

(17) **ISO-NE Emergency**

The emission limits contained in this license do not apply if the facility, during an electricity supply emergency, is directed by Independent System Operator – New England (ISO-NE) to operate at low loads such that the SCR cannot be operated because of unstable temperatures. During such operation, Verso Cogen shall use best operational practices to minimize emissions of air pollutants and shall operate the SCR as soon as practicable once temperatures stabilize. [06-096 CMR 140, BPT]

(18) **Glycol System Heaters #1 and #2** [06-096 CMR 140, BPT]

A. Glycol System Heaters #1 and #2, each with a maximum capacity of 3.05 MMBtu/hour, shall fire natural gas.

B. Emissions from the system heaters shall not exceed the following:

| **Unit** 3.05 MMBtu/hr each, natural gas | **PM (lb/MMBtu)** | **PM (lb/hr)** | **$PM_{10}$ (lb/hr)** | **$SO_2$ (lb/hr)** | **$NO_x$ (lb/hr)** | **CO (lb/hr)** | **VOC (lb/hr)** |
|---|---|---|---|---|---|---|---|
| System Heater #1 | 0.05 | 0.15 | 0.15 | 0.01 | 0.3 | 0.25 | 0.02 |
| System Heater #2 | | 0.15 | 0.15 | 0.01 | 0.3 | 0.25 | 0.02 |

C. Compliance with the above emission limits shall be demonstrated through stack testing upon request of the Department and in accordance with the appropriate method found in 40 CFR Part 60, Appendix A.

D. Visible emissions from either System Heater #1 or #2 firing natural gas shall not exceed 10% opacity on a six-minute block average basis, except for no more than one six-minute block average in a three-hour period.

E. NESHAPs 40 CFR Part 63, Subpart DDDDD

1. Compliance Dates

Verso Cogen shall comply with the applicable requirements of 40 CFR Part 63, Subpart DDDDD no later than January 31, 2016. [40 CFR §63.7495(b)] However, some notifications must be submitted before the facility is required to comply with the applicable work practice standards and recordkeeping and reporting requirements. [40 CFR §63.7495(d)]

2. Work Practice Standards

a. Verso Cogen shall complete initial tune-ups of System Heaters #1 and #2 by following the procedures described in § 63.7540(a)(10)(i) through (vi) no later than January 31, 2016. [40 CFR §63.7510(e)]

b. Subsequent tune-ups must be conducted on System Heaters #1 and #2 every five years and as specified in §63.7540. [40 CFR §63.7500(e)]

c. Each five-year tune-up must be conducted no more than 61 months after the previous tune-up. [40 CFR §63.7515(d)]

d. Verso Cogen shall have a one-time energy assessment performed by a qualified energy assessor no later than January 31, 2016, or comply with any amended requirements of the rule. The energy assessment must include the elements specified in Part 4 of Table 3 of Subpart DDDDD, or as may be amended. [40 CFR §63.7500(e)]

An energy assessment completed on or after January 1, 2008, that meets or is amended to meet the aforementioned energy assessment requirements is valid. A facility that operates under an energy management program compatible with ISO 50001 that includes applicable boilers and process heaters satisfies the energy assessment requirements.

3. Recordkeeping and Reporting

   a. Verso Cogen shall maintain records in accordance with 40 CFR §63.7555.

   b. Records shall be in a form suitable and readily available for expeditious review, according to § 63.10(b)(1).

   c. Verso Cogen shall submit a compliance report for the one-time energy assessment and for each tune-up required, as applicable, by 40 CFR Part 63, Subpart DDDDD, in accordance with 40 CFR §63.7550.

(19) **Fugitive Emissions**

Visible emissions from any fugitive emission source, including stockpiles and roadways, shall not exceed 20 % opacity, except for no more than five minutes in any one-hour period. Compliance shall be determined by an aggregate of the individual fifteen-second opacity observations which exceed 20% in any one hour. [06-096 CMR 101]

(20) **Parameter Monitor General Requirements** [06-096 CMR 140 and 117]
**Enforceable by State-only**

A. Parameter monitors required by this license shall be installed, operated, maintained, and calibrated in accordance with manufacturer recommendations, by industry general consensus standards, as modified by in-practice knowledge, or as otherwise required by the Department.

B. Parameter monitors required by this license shall continuously monitor data at all times the associated emissions unit is in operation. "Continuously" with respect to the operation of parameter monitors required by this license means providing equally spaced data points with at least one valid data point in each successive 15-minute period. A minimum of three valid 15-minute periods constitute a valid hour.

C. Each parameter monitor must record accurate and reliable data. If the parameter monitor is recording accurate and reliable data less than 98% of the associated emissions unit operating time within any quarter of the calendar year, the Department may initiate enforcement action and may include in that enforcement action any period of time that the parameter monitor was not recording accurate and reliable data during that quarter unless the licensee can demonstrate to the satisfaction of the Department that the failure of the system to record accurate and reliable data was due to the performance of established quality assurance and quality control procedures or unavoidable malfunctions.

(21) **CEMS Recordkeeping** [06-096 CMR 140] **Enforceable by State-only**

A. The licensee shall maintain records documenting that all CEMS are continuously accurate, reliable, and operated in accordance with 06-096 CMR 117 (as amended), 40 CFR Part 51, Appendix P, and 40 CFR Part 60, Appendices B and F, or 40 CFR Part 75, as applicable;

B. The licensee shall maintain records of all measurements, performance evaluations, calibration checks, and maintenance or adjustments for each CEMS as required by 40 CFR Part 51 Appendix P; and

C. The licensee shall maintain records of other data indicative of compliance with the applicable emission standards for those periods when the CEMS were not in operation or produced invalid data. In the event the Department does not concur with the licensee's compliance determination, the licensee shall, upon the Department's request, provide additional data, and shall have the burden of demonstrating that the data is indicative of compliance with the applicable standard.

(22) **Quarterly Reporting**

The licensee shall submit a Quarterly Report to the Department within 30 days after the end of each calendar quarter detailing the following for all control equipment, parameter monitors, and CEMS required by this license. [06-096 CMR 117]

A. All control equipment downtimes and malfunctions;
Control equipment on each Combustion Turbine #1, #2, and #3includes the following:
   1. Water Injection Systems;
   2. SCR Systems; and
   3. Oxidation Catalysts.

B. All CEMS downtimes and malfunctions;

C. All parameter monitor downtimes and malfunctions;

D. All excess events of emission and operational limitations set by this Order, Statute, and state or federal regulations, as appropriate. The following information shall be reported for each excess event:
   1. Standard exceeded;
   2. Date, time, and duration of excess event;
   3. Amount of air contaminant emitted in excess of the applicable emission standard, expressed in the units of the standard;
   4. A description of what caused the excess event;
   5. The strategy employed to minimize the excess event; and
   6. The strategy employed to prevent reoccurrence.

E. A report certifying there were no excess emissions, if that is the case.

(23) **Semiannual Reporting [06-096 CMR 140]**

A. The licensee shall submit to the Department semiannual reports which are due on January 31st and July 31st of each year. The facility's designated responsible official must sign this report.

B. The semiannual report shall be considered on-time if the postmark of the submittal is before the due date or if the report is received by the Department within seven calendar days after the due date.

C. Each semiannual report shall include a summary of the periodic monitoring required by this license.

D. All instances of deviations from license requirements and the corrective action taken must be clearly identified and provided to the Department in summary form for each six-month interval.

(24) **Annual Compliance Certification** [06-096 CMR 140]

Verso Cogen shall submit an annual compliance certification to the Department in accordance with Standard Condition (13) of this license. The annual compliance certification is due January 31st of each year. The facility's designated responsible official must sign this report.

The annual compliance certification shall be considered on-time if the postmark of the submittal is before the due date or if the report is received by the Department within seven calendar days of the due date. Certification of compliance is to be based on stack testing or monitoring data required by this license. If the license does not require such data or the license requires such data upon request of the Department and it has not been requested the testing or monitoring, compliance may be certified based upon other reasonably available information such as the design of the equipment or applicable emission factors.

(25) **Annual Emission Statement** [06-096 CMR 137]

In accordance with *Emission Statements*, 06-096 CMR 137 (as amended), the licensee shall annually report to the Department, by the date as specified in 06-096 CMR 137, the information necessary to accurately update the State's emission inventory by means of either of the following:

A. A computer program and accompanying instructions supplied by the Department; or
B. A written emission statement containing the information required in 06-096 CMR 137.

(26) **Acid Rain**

Verso Cogen shall continue to comply with the federal Acid Rain Program, 40 CFR Part 70, *State Operating Permits Program*, and Part 72, *Permits Regulation*, in accordance with the Phase II acid rain permit, A-718-70-A-S, issued November 12, 1998.

(27) **$CO_2$ Budget Source**

Verso Cogen shall continue to comply with the requirements of license A-718-78-A-N, issued January 15, 2009, per Maine's *$CO_2$ Budget Trading Program*, 06-096 CMR 156 (as amended) for Combustion Turbines #1, #2, and #3.

(28) **General Applicable State Regulations**

The licensee is subject to the State regulations listed in the following table:

| Origin and Authority | Requirement Summary | Enforceability |
|---|---|---|
| 06-096 CMR 102 | Open Burning | -- |
| 06-096 CMR 109 | Emergency Episode Regulation | |
| 06-096 CMR 110 | Ambient Air Quality Standard | |
| 06-096 CMR 116 | Prohibited Dispersion Techniques | |
| 38 M.R.S.A. §585-B, §§5 | Mercury Emission Limit | **Enforceable by State-only** |

(29) **Units Containing Ozone Depleting Substances**

When repairing or disposing of units containing ozone depleting substances, the licensee shall comply with the standards for recycling and emission reduction pursuant to 40 CFR Part 82, Subpart F, except as provided for motor vehicle air conditioning units in Subpart B. Examples of such units include refrigerators and any size air conditioners that contain CFCs. [40 CFR, Part 82, Subpart F]

(30) **Risk Management Plan**

The licensee is subject to all applicable requirements of 40 CFR Part 68, *Chemical Accident Prevention Provisions*.

(31) **Expiration of a Part 70 license**

A. Verso Cogen shall submit a complete Part 70 renewal application at least six months but no more than 18 months prior to the expiration of this air emission license.

B. Pursuant to Title 5 MRSA §10002, and 06-096 CMR 140, the Part 70 license shall not expire and all terms and conditions shall remain in effect until the Department takes final action on the renewal application of the Part 70 license. An existing source submitting a complete renewal application under 06-096 CMR 140 prior to the expiration of the Part 70 license will not be in violation of operating without a Part 70 license. **Enforceable by State-only**

(32) **New Source Review**

Verso Cogen is subject to all previous New Source Review (NSR) requirements summarized in this Part 70 air emissions license, and the NSR requirements remain in effect even if this 06-096 CMR 140 Air Emissions License, A-718-70-E-R/A, expires.

DONE AND DATED IN AUGUSTA, MAINE THIS 22 DAY OF October , 2013.

DEPARTMENT OF ENVIRONMENTAL PROTECTION

BY: Marc Allen Robert Cone for
PATRICIA W. AHO, COMMISSIONER

**The term of this license shall be five (5) years from the signature date above.**

[Note: If a complete renewal application as determined by the Department, is submitted at least 6 months but no earlier than 18 months prior to expiration of this Part 70 license, then pursuant to Title 5 MRSA §10002, all terms and conditions of the Part 70 license shall remain in effect until the Department takes final action on the Part 70 license renewal application.]

PLEASE NOTE ATTACHED SHEET FOR GUIDANCE ON APPEAL PROCEDURES

Date of initial receipt of application: January 30, 2008
Date of application acceptance: February 21, 2008

Date filed with the Board of Environmental Protection:

This Order prepared by Jane E. Gilbert, Bureau of Air Quality.

Filed
OCT 22 2013
State of Maine
Board of Environmental Protection